Service Date: December 8, 1987

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER of the Application of	)	UTILITY DIVISION
PACIFIC POWER AND LIGHT COMPANY for	)	DOCKET NOS. 86.12.76
Authority to Adopt New Rates and	)	86.11.61
Charges for Electric Service Fur-	)	86.11.62(14)
nished in the State of Montana.	)	ORDER NO. 5311

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DEPARTMENT OF PUBLIC SERVICE REGULATION
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* * * * *

IN THE MATTER of the Application of PACIFIC POWER AND LIGHT COMPANY for Authority to Adopt New Rates and Charges for Electric Service Furnished in the State of Montana.	)	UTILITY DIVISION DOCKET NOS. 86.12.76 86.11.61 86.11.62(14) ORDER NO. 5311

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BEFORE:

HOWARD L. ELLIS, Commissioner, Presiding

TOM MONAHAN, Commissioner

DANNY OBERG, Commissioner

JOHN B. DRISCOLL, Commissioner

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TOM MONAHAN, Commissioner
DANNY OBERG, Commissioner
JOHN B. DRISCOLL, Commissioner

FINDINGS OF FACT

PART A

BACKGROUND

The Pacific Power and Light Company (PP&L, Company, or Applicant) is a public utility furnishing electric services to consumers in the State of Montana, and is subject to the regulatory jurisdiction of the Montana Public Service Commission (PSC or Commission). The Company serves approximately 30,000 electric customers in Montana.

On December 30, 1986, PP&L filed with the Commission its application for authority to decrease rates and charges for electric service in Montana. The proposed rates are designed to produce no additional annual revenues from its Montana electric operations. The Company estimates that an additional $135,000 can be recovered from the Bonneville Power Administration (BPA), pursuant to the terms of the Company's Residential Purchase and Sale Agreement with BPA, authorized by the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act). Therefore, the proposed tariff schedules are designed to produce a net revenue decrease of $135,000 or 0.5 percent. PP&L also proposed extensive changes in the areas of cost of service and residential rate design.

Based on a test year ended June 30, 1986, the Company presented testimony and exhibits in this filing showing that it could support an annual revenue increase of over $1.1 million. However, PP&L is not requesting an overall revenue increase in this filing.

In its transmittal letter of the filing, PP&L stated that the purpose of this filing was to accomplish four objectives. First, the Company desires to pass through to customers the impact of the 1986 Tax Act. Second, the filing incorporates the costs associated with the recently installed pollution control devices at Jim Bridger Unit 2 and Wyodak into the Montana results of operation. Third, the filing implements changes in the jurisdictional allocation methodology. Fourth, the filing addresses residential rate design and reflects a change in the Schedule 98 credit for qualifying customers based upon changes in the Company's average system cost.

Concerning the proposed changes to residential rate design, the Company presented a two-phase modification. Phase I would move from the present inverted rate structure to a flat energy charge. Phase II would move from a flat energy charge to a declining block energy charge.

On January 13, 1987, the Commission issued a Notice of Application and Proposed Procedural Order. On January 27, 1987, the Commission issued a final Procedural Order.

The Montana Consumer Counsel (MCC) has participated in this Docket on behalf of electric utility consumers since the inception of these proceedings, and the Commission granted MCC's Motion to Intervene on January 22, 1987.

On February 3, 1987, the Commission granted the petition of the Natural Resources Defense Council for leave to intervene in this Docket.

On February 9, 1987, the Commission voted to consolidate the further consideration of Docket No. 86.11.61 (PP&L's Experimental Clean Air/Winter Saver Residential Rate) into Docket No. 86.12.76.

On February 19, 1987, the Commission issued a Notice of Staff Action, which amended the Procedural Order in this Docket without changing the hearing date.

On March 16, 1987, the Commission issued a Notice of Staff Action which granted Montana Consumer Counsel's request to amend the Procedural Order in this Docket.

On March 24, 1987, the Commission issued a Notice of Staff Action indicating that a Stipulation between Montana Con sumer Counsel and the Company had been filed with the Commission on March 3, 1987, and that a public meeting was scheduled for March 30, 1987, at 9 a.m. to discuss and review the Stipulation.

On March 25, 1987, the Commission issued a Notice of Staff Action which changed the opening day of the hearing to May 5, 1987, at 9 a.m.

On April 3, 1987, the Commission issued a Notice of Public Hearing in Docket No. 86.12.76.

On May 5 and 6, 1987, pursuant to the Notice of Public Hearing, a hearing was held in Kalispell, Montana, and satellite public hearings were held in Libby and Kalispell, Montana, on the evenings of May 5 and 6, 1987, respectively.

On July 21, 1987, the Commission issued a Notice of Commission Action approving Montana Consumer Counsel's request to amend the briefing schedule so that initial briefs would be due from all parties on August 10, 1987, and that reply briefs would be due from all parties on August 21, 1987.

On August 10, 1987, the Commission received from PP&L and NRDC a Stipulation resolving all contested issues between these parties. A public meeting with all parties to this Docket was held by the Commission on August 13, 1987, to discus the merits of the Stipulation. On September 11, 1987, a subsequent Stipulation was filed between all parties to this Docket, resolving all contested issues between them. At a subsequent public meeting, the Commission determined that an additional meeting with all the parties to this Docket was unnecessary.

Applicant proposes a June 30, 1986, test year adjusted for known and measurable changes, to be used as the test period in this Docket. The June 30, 1986, test period is found by the Commission to be a reasonable period within which to measure Applicant's electric utility revenues, expenses, rate base, and returns for the purpose of determining a fair and reasonable level of rates for electric service.

PART B

REVENUE REQUIREMENTS STIPULATION

Rate of Return, Rate Base, Revenues, Expenses, and Revenue Requirements

On March 3, 1987, the Commission received a Stipulation regarding the issues of revenue requirement and cost of capital entered into by PP&L and MCC. The Company and MCC agreed in the Stipulation to settle the issues of revenue requirement (revenue deficiencies) and cost of capital (rate of return) in Docket Nos. 86.12.76 and 86.11.62 (14). The Commission's Show Cause Docket No. 86.11.62 (14) requires regulated utilities doing business in Montana to demonstrate the impact on the individual utility's financial posture of the passage of the Tax Reform Act of 1986 (TRA).

The MCC and its retained consultant have analyzed Company responses to data requests and have conducted further inquiry in this proceeding by conducting a discovery audit at the Company's offices in Portland, Oregon.

As a result of the analyses and subsequent negotiations, the Company and the MCC stipulate and agree, subject to the approval of the Commission, that the Company's revenue needs (see the Direct Testimony of James T. Watson, Exh. 1, page 2, lines 1-3) reflect the 1987 calendar-year impact of the TRA and would not result in the Company realizing an excessive or unjust return on its Montana operations.

The Company and MCC agree that this Stipulation is made for settlement purposes only and it is the express intent of the Company and MCC that this agreement is meant to address the following issues: (1) the Company's requested revenues from its Montana operations; (2) the Company's current cost of capital/rate of return requirement; and (3) the 1987 calendar-year impact of the TRA on the Company's Montana operations.

PP&L and MCC agree that the matters settled herein do not constitute and cannot be considered as precedent for any future proceeding. It is expressly understood and agreed that neither of the parties to this Stipulation, by entry into this Stipulation, shall be deemed to have accepted, agreed to, or conceded to any particular ratemaking principle, cost of service determination, or legal principle underlying any of the provisions of this Stipulation.

MCC and PP&L agree that neither party, by consenting to the approval of this Stipulation by the Commission waives any claim, right, defense, or legal argument which it may otherwise have with respect to any matters specified in the Stipulation.

Based on its analysis of all relative testimony, exhibits, data responses, calculations, and cross-examination concerning the proposed Stipulation in this proceeding, the Commission approves the revenue requirements/rate of return/TRA Stipulation for purposes of this proceeding, as well as Docket No. 86.11.62(14), the consideration of which is consolidated into this Docket by this Order. The Commission believes that the reflection of the TRA as proposed in this proceeding does not cause a need to change PP&L's annual revenue requirements in this Docket. The Commission, however, is also aware that this Stipulation utilizes a Federal tax rate of 40 percent rather than the level of 34 percent approved in Order No. 5236c in Docket No. 86.11.62, of which PP&L is a party in sub 14. Because of the magnitude of the revenue deficiency shown in this proceeding, the Commission finds that the use of 40 percent is acceptable because PP&L did not ask for an increase in its revenue requirements in this Docket. However, and in order to put PP&L in complete compliance with Order No. 5236c, the Company must file with the Commission so that the effects of moving to a 34 percent tax rate will be in effect no later than January 1, 1988. In accepting this Stipulation, the Commission also re minds the parties that all issues and matters in this filing will again be closely scrutinized in the next general filing of PP&L and that the Commission's acceptance of the Stipulation in this proceeding will have no bearing on its decisions in any future proceedings.

PART C

COST OF SERVICE

Introduction: Cost of Service and Rate Design

The issues that will be addressed in this section of the Order include "cost of service" (COS) and "rate design" (RD). Cost of service issues determine how revenue requirements should be allocated to various rate classes, while rate design issues impact how prices for the various goods and services should be set. Additional issues that do not neatly fall into one of these two categories are discussed in a later section.

A COS/RD model involves numerous steps to arrive at final pricing structures. Table 1 below illustrates some of the steps involved in setting prices under the existing regulatory institution. Generally, COS functionalizes costs into three or four components, including generation, transmission, distribution, and customer. Costs are then classified within each function into demand costs, energy costs and commitment costs. Costs may be further refined to reflect time of use and voltage level of service variations. Once COS has been determined, a reconciliation procedure is used to adjust each class' revenue requirement (as determined by COS) so that the summation of all class marginal cost revenue requirements equal the allowed revenue requirement. Prices may be designed using classified costs: basic charges ($/customer), demand charges ($/kW), reactive power charges ($/kvar) and energy charges (¢/kWh). The model described in Table 1 is very general and excludes the many de tailed technical steps needed to perform a cost of service study.

Table 1. A General Cost of Service Rate Design Model

Function	Cost of Service Classified	Allocated	Reconciled	Rate Design
Generation Transmission Distribution	Energy, Demand & Customer Access	Seasons, Time-of-day and Customer Classes	Uniform percent or other, e.g., market based	¢/kWh, $/kW, $/cust.

The organization of the balance of the COS/RD portion of this Order follows the general model in Table 1. First each party's proposed COS study is reviewed. Next, each party's proposed reconciliation procedure is reviewed. Then each party's rate design recommendations are reviewed.

The structure of an Order would normally present the Commission's findings after each COS/RD issue is reviewed. However, in this proceeding, the principle parties have entered into a Stipulation designed to resolve all contested issues. Therefore, the Order will review the Stipulation, and then present the Commission's findings, and then present the Commission's findings on the Stipulation and COS/RD issues. Lastly, other issues not related to COS/RD e.g., PP&L's proposed account service charge, are reviewed and decided by the Commission.

Background: Cost of Service and Rate Design

Prior to PP&L's filing of Docket No. 86.12.76, the Commission's most recent decisions on PP&L cost of service and rate design stemmed from Order No. 5169a, Docket No. 85.10.41. That Order accepted the Company's proposal to use a 21-year stream of future generation costs to calculate marginal generation costs, rather than escalating the single cost of a distant resource acquisition. Rate design decisions in Order No. 5169a included a 100 percent increase in the customer charge (from $2 to $4/month) combined with a reduction in the inverted block differential for the residential rate class.

Two parties filed COS studies in this proceeding, PP&L and the MCC. PP&L's testimony, sponsored by Mr. Gregory N. Duvall, is reviewed first followed by a review of the MCC's testimony, sponsored by Mr. James H. Drzemiecki.

PP&L Cost of Service

Generation. PP&L uses a Base-Peak approach to classify generation demand and energy costs. Under the Base-Peak approach, generation demand costs are measured using a 20-year forecast of the Company's marginal resource, BPA Firm Capacity (CF-85). PP&L projects that it will have a surplus of capacity until 1991 and paces a zero value on generation demand until then. Generation demand costs for the remaining years (1991-2005) are measured using forecast BPA CF-85 rates. This 20-year stream of generation demand costs is then levelized using nominal interest rates and then annualized using a real carrying charge. This calculation results in marginal generation demand costs of 21.61 $/kW (Exh. 6, p. 03-002).

The Company uses a real carrying charges to annualize generation, transmission, and distribution plant. The carrying charge for generation plant is based on a 20 year service life and a real cost of capital of 6.19 percent, resulting in a carrying charge of 9.30 percent (Exh. 6, p. 03-002). The transmission carrying charge of 12.56 percent is developed using a real cost of capital of 7.38 percent and a service life of 40 years. The carrying charge for distribution is developed using a 25 year service life and a cost of capital of 7.38 percent, resulting in a carrying charge of 14.23 percent (Exh. 6, p. 14-001).

The Base-Peak approach measures marginal generation energy costs by subtracting the fixed costs of peakload capacity from the fixed costs of baseload capacity, and adding the result to the variable costs of baseload capacity. PP&L uses forecasts of its "avoided costs" (as calculated in its COS study) and BPA 7(f) rates are used to calculate baseload generation capacity and energy costs. Avoided costs are used to measure baseload generation capacity and energy for the first 8 years and BPA 7(f) rates for the last 12 years. Baseload generation capacity costs are then levelized and annualized in the same manner as peakload generation costs. Baseload generation capacity and energy costs of 179.78 $/kW less peakload generation capacity costs of 21.61 $/kW results in the net marginal generation energy costs of 158.17 $/kW (Exh. 6, p. 03-002).

Generation demand and energy costs are further allocated to seasons and customer classes. The methodology used to make those allocations is presented in a section devoted to seasonal allocations.

<u>Transmission</u>. Transmission plant is also classified to demand and energy. The Company bases its calculation of marginal transmission costs on planned investment in system-wide transmission plant for the next five years. Planned investment is then classified as growth-related or non-growth-related investment on a project by project basis. Growth-related investment is defined by the Company to be investment undertaken to accommodate growth in system demand (Exh. 6, pp. 05-002, 05-003).

Growth-related transmission investments are then separated into demand and energy-related costs in the same proportions as generation plant. These costs are then levelized and annualized in the same manner as generation, and loaded for Operation & Maintenance (O&M) expenses, resulting in marginal transmission costs. The Company calculates marginal transmission demand costs to be 18.50 $/kW and marginal transmission energy costs to be 15.83 $/kW (Exh. 6, pp. 05-002,05-003).

Marginal transmission energy costs are converted from a $/kW price to a mills/kWh price, using the following formula:

$$\frac{15.83\ \$/kW}{8760 * .66} = 2.738\ mills/kWh$$

where: 8760 = Number of hours in a year
.66 = System Load Factor (Exh. 6, p. 05-003).

Transmission demand and energy costs are further allocated to seasons and customer classes. The methodology used to make those allocations is presented in a section devoted to seasonal allocations.

Distribution. Distribution costs are classified into three components; demand, energy, and commitment costs. The Company defines commitment-related costs to be the minimum distribution system required to connect every customer to the system, with no energy usage. Distribution energy costs are not computed as a cost per kilowatt-hour, but are derived using line losses in the seasonality of energy calculations.

The calculation of long-run marginal distribution costs uses the following components; 1) existing investment in distribution plant in Montana as listed in FERC Form No. 1; 2) the Company's planned investments in distribution for the next five years; 3) the Cheney Feeder Study (a Company study used to allocated distribution plant between demand and commitment costs);

4) the Company's five year forecast for peak load growth in Montana; and 5) the Company's five year forecast for customer growth in Montana.

The first component, existing distribution plant in Montana, is separated into "Primary" and "Other" (not voltage levels) transmission plant. The Company considers FERC accounts 364, 365, and 368 to be in the "Primary" category of distribution investment, various other FERC distribution plant accounts make up the "Other" category. Existing investment in distribution is used to spread planned investment in distribution, (the second component), to FERC accounts in the same proportion as existing investments (Exh. 6, p. 07-003 through p. 07-006).

The Cheney Feeder Study, the third component, was conducted by PP&L on a portion of the Company's distribution system in Oregon. The Company felt that this portion of the distribution system "best" represented the average distribution system. The results of that study are used to classify marginal distribution between demand and commitment-related costs (Exh. 6, p. 07-003).

The Company's forecast growth in Montana's system peak over the next five years is the fourth component. The marginal growth rate for Montana's system peak is determined for each year and is accumulated for the five year period, resulting in the long-run net increase in MW demand in Montana (marginal MWs) (Exh. 6, p. 08-003). Increased demand in Montana is then used to spread "primary" demand costs to customer classes. The Company computed marginal distribution demand costs of 18.86 $/kW for the residential customer class (Exh. 6, p. 07-001).

Distribution demand costs are further allocated to seasons and customer classes. The methodology used to make those allocations is presented in a section devoted to seasonal allocations.

Marginal distribution commitment costs are allocated to customer classes using a five year forecast of customer growth. The sum of five years forecast growth in residential and "other" customers equals long-run "marginal customers", the fifth component (Exh. 6, p. 08-001). "Marginal customers" are then used to spread primary distribution commitment costs to customer classes. The Company calculates marginal distribution commitments costs of 65.56 $/year per customer for the residential class (Exh. 6, p. 07-001).

Customer. The Company measures marginal customer costs as the billing-related costs of serving a customer. The Company's billing costs include the average annual installed costs for meters and service drops, and costs that can be attributed to accounting, service and information, and meter O&M expenses. The Company estimates marginal customer costs are 68.18 $/year per residential customer (Exh. 6, p. 07-001).

Marginal distribution commitment costs and customer costs are combined to get total customer-related costs of 134.37 $/year, or 11.20 $/month, per residential customer.

Seasonality. PP&L allocates demand and energy costs of the three major functions (Generation, Transmission, and Distribution) to the "summer" and "winter" seasons. The Company uses the existing seasonal definition to develop demand and energy seasonality (Exh. 6, p. 04-001).

Seasonality of Demand. The Company allocates demand costs to seasons based on the relationship that the cost of the summer peak added to the cost of the winter peak should equal the cost of the annual peak, or:

(W $/kW)*(W peak) + ($ $/kW)*(S peak) = (A $/kW)*(A peak).

where: W = winter
S = summer
A = annual

Summer and winter peaks are developed for each rate class from annual MWHs use and System Diversified Load Factors (SDLF). These peaks are then used to develop a Summer/Winter (S/W) peak relationship (Exh. 6, p. 04-003).

A S/W relationship for the cost of marginal capacity is also developed. However, since the Company's marginal re source (BPA-CF rates) has no cost seasonality the S/W cost ratio is 1.0 (Exh. 6, p. 04-002).

The two S/W relationships are then used to allocate generation, transmission, and distribution demand to seasons. Generation and transmission demand costs are allocated to seasons on a system-wide basis, while the demand costs of distribution are allocated by class (Exh. 6, p. 04-003).

Seasonality of Energy. The energy costs of generation, transmission, and distribution are also spread to seasons (Exh. 6, p. 04-004). Seasonality of generation energy is developed using a S/W cost of energy relationship and adjusted seasonal energy usage, while transmission energy costs are allocated equally to seasons.

The S/W cost relationship for generation energy is developed using a month by month 20-year forecast of short-run marginal costs. These short-run marginal costs are made up of a weighted average of opportunity costs, system lambda, and purchased power costs for the first 8 years of the forecast. The Company uses BPA forecast 7(f) rates, (energy only), as the marginal resource for the remaining 12 years of the forecast. These costs are then levelized and summed, by season. A ratio of these seasonal costs result in the S/W energy cost relationship (Exh. 6, p. 04-001).

Adjusted seasonal energy usage is estimated from class energy use by season and energy losses by class and season. The Company develops energy losses first by line sizes, and then by class (Exh. 6, p. 15-001). Seasonal energy losses by class reflect marginal distribution energy costs by class. Adjusting seasonal energy use by class for seasonal energy losses results in seasonal adjusted MWHs by class. Summing all classes adjusted MWH use results in adjusted MWHs for the entire Montana system. The S/W cost relationship and adjusted seasonal use are then used to spread marginal generation energy costs to seasons (Exh. 6, p. 04-004).

Marginal transmission energy costs are spread to seasons by tacking on a flat transmission charge to marginal generation energy costs in each season (Exh. 6, p. 04-004).

<u>Changes to COS</u>. Several changes have occurred in the Company's COS study since the last general rate case, Docket No. 85.10.41. In that docket the Company allocated demand-related transmission costs entirely to the system annual peak, the winter

season. In the instant docket, the Company allocates transmission costs, both demand and energy, equally to seasons. The testimony offered by Greg Duvall provides the Company's basis for this change:

> Q. How has the seasonal allocation of transmission costs been improved?
>
> A. In the 1985 study, demand-related transmission costs were allocated entirely to the winter season. An inspection of the Company load data shows that in 1985 the system summer peak load was 76 percent of the winter peak load. However, because lower summer loads correspond with lower summer transmission availability based on thermal ratings of the transmission lines, it appears reasonable that transmission costs be allocated equally to both summer and winter seasons (Exh. 5, p. 3).

The other change is in the way the Company calculates the O&M loading factor that is applied to transmission and distribution plant. In Docket No. 85.10.41 this O&M loading factor was based on the ratio of O&M expenses to total transmission and distribution over the past ten years. This ratio was then applied to transmission and distribution plant additions for the forecast period. In this docket, the Company has calculated O&M loading factor based on a ratio of O&M expenses to the total replacement cost of vintage transmission and distribution plant (Exh. 5, p. 3).

Summary. Table 2 illustrates the Company's calculation of marginal costs for the residential rate class. The Company calculates the long-run marginal costs of demand at 1.308 ¢/kWh and energy at 2.310 ¢/kWh, resulting in long-run marginal costs of demand and energy of 3.609 ¢/kWh. Commitment and billing-related costs of 1.188 ¢/kWh brings total marginal costs to 4.797 ¢/kWh for the residential rate class.

Table 2. PP&L's Residential Class Marginal Costs at the Meter

Description	Amount
Demand	$0.01308/kWh
Energy	$0.02301/kWh

Demand & Energy Subtotal	$0.03609/kWh
Commitment & Billing	$0.01188/kWh

Total Marginal Cost	$0.04797/kWh

* Source: Exh 6, Table 6-1

MCC Cost of Service

Overview. The COS analysis presented by the MCC differs from the Company's model. While the Company's model functionalizes total utility plant into generation, transmission, and distribution, MCC's model functionalizes total plant into bulk power supply, distribution, and customer costs. The testimony offered by Mr. Drzemiecki provides the basis for using a bulk power functionalization:

> A separation of bulk power supply costs from other system costs is appropriate because they are over three-fourths of the total costs of the electrical supply and they are also the costs that vary most by time of use (Exh. MCC-2, p. 23).

Bulk power is, in turn, comprised of generation and higher voltage transmission plant.

Bulk Power. Bulk Power supply is classified to demand or energy. Demand is further classified as either generation demand or transmission demand costs. MCC uses a combustion turbine peaking unit (CT) as PP&L's marginal resource. The cost of a CT (357.00 $/kW) is annualized using a real carrying charge of 12.56 percent. The annual cost is then adjusted for fixed O&M and a 19 percent reserve margin, resulting in a long-run marginal generation demand costs of 53.84 $/kW (Exh. MCC-2, J.D.-1, p. 2).

Using similar logic, MCC uses the investment needed to hook a CT into the transmission system as PP&L's marginal cost of transmission plant, (33.00 $/kW). The cost of the inter-tie between a CT and the existing transmission system is also annualized and adjusted the same as the CT, resulting in a long-run marginal cost of transmission demand of 5.16 $/kW (Exh. MCC-2, J.D.-1, p. 3).

MCC adopts the Company's marginal energy costs, developed in the generation and transmission portion of the Company's COS study, as the appropriate energy costs for bulk power supply (Exh. MCC-2, pp. 46-47).

Distribution. MCC uses the Company's embedded costs of distribution as listed in the Montana FERC Form No. 1 to measure marginal distribution costs. Table 3 contains a listing of these accounts and the percentage classified to demand by the Company and MCC. MCC uses the embedded costs in these accounts to approximate marginal distribution costs. MCC then classifies these costs to customer classes in proportion to their peak demand (Exh. MCC-2, pp. 50-51). In the Company's COS study, the investments in these FERC accounts were used only to classify planned distribution plant investment to demand and commitment costs.

Table 3. Comparison of Classification of Distribution Plant

Account	Description	Percent Classified to Demand	
		PP&L	MCC
360	Land and Land Rights	90%	100%
361	Structures	90%	100%
362	Station Equipment	90%	100%
364	Poles, Towers, etc.	40%	100%
365	Overhead Conductors	70%	100%
366	Underground Conduit	80%	100%
367	Underground Conductors	50%	100%
368	Line Transformers	60%	100%

* Source: MCC-2, p. 49.

In testimony presented before the Commission in Montana Dakota Utilities (MDU) Docket No. 86.5.28, the MCC followed a similar procedure to obtain MDU's distribution costs. However, in that docket MCC excluded FERC accounts 360, 361, and 362 from the calculation of distribution demand costs, as did MDU (Finding of Fact No. 259, Docket No. 86.5.28, Order No. 5219b).

Customer. PP&L's marginal customer costs are approximated using the Company's embedded billing-related costs. Those costs include the average annual installed costs for meters and service drops, and costs that can be attributed to accounting, service and information, and meter O&M expenses (Exh. MCC-2, pp. 51-52).

PART D

RECONCILIATION

Background: Reconciliation

The Commission's last decisions regarding reconciliation procedures are found in the Company's last general rate case, Docket No. 85.10.41, Order No. 5169a. In that docket Company proposed to achieve final rate spread goals using a uniform percent methodology. A uniform percent methodology moves each class' present revenues towards their marginal cost by the same percentage.

In this docket, the MCC's COS study is the only study submitted which requires a reconciliation procedure.

MCC Reconciliation

MCC's COS study finds that the revenue from marginal cost pricing would fall short of the stipulated revenue requirement. MCC proposes to make up this shortfall by multiplying the marginal cost of bulk power by a factor of 1.297. Additional costs would then be allocated to classes proportionally. Such an adjustment changes the revenue responsibility of various customer classes, decreasing the residential class revenue responsibility and increasing all other class' revenue responsibility (Exh. MCC-2, pp. 53-55).

MCC's COS study and reconciliation procedure results in a reduction of the residential class' revenue responsibility of 6.16 percent. However, MCC proposes that the residential rate class only be allowed a 5.0 percent decrease in class revenue responsibility (Exh. MCC-2, pp. 55-57).

PART E

RATE DESIGN

PP&L Rate Design

Overview. Rate design has become the principle issue of this rate case due to the residential rate design changes proposed by the Company. Summarizing rate design issues, the Company proposes to implement three changes to residential prices; 1) increase the basic charge for the residential rate class from $4.00 to $6.00; 2) in a two step phase-in, change the present inverted block rate structure into a declining block rate structure; and 3) move from seasonally differentiated prices to non-seasonally differentiated prices (Exh. 9).

The Company proposes that the monthly basic charge be increased from $4.00 to $6.00 to reflect commitment and billing costs the Company currently estimates to be $11.20 per month (Exh. 7, p. 7).

The first step of the two step phase-in would increase the basic charge to $6.00 and change the net energy charge to a flat, non-seasonally differentiated rate of 4.239 ¢/kWh. The second step of the phase-in would then change the energy charge to a declining block rate with the first energy block set at 600 kWh/month. The Company selected 600 kWh/month as the cut off point for the first block as it, "approximately equals the average basic monthly electrical needs of our Montana residential customers" (Exh. 7, pp. 7-8). The net energy charge for the first block would be 4.685 ¢/kWh, and all additional energy would be priced at 3.773 ¢/kWh. The testimony offered by Mr. Servaitis presents the Company's basis for proposing a declining block residential rate structure:

> The Company believes that the declining block structure sends the appropriate pricing signals to customers with price sensitive consumption and provides an opportunity for Pacific to better compete with wood and other alternative energy suppliers as a space heating fuel. (Exh. 7, pp. 7-8)

Other Changes. Other rate design issues include the addition of an account service charge, changes in the basis for interest rates on customer deposits, and the addition of a standby power rate, Schedule 33T.

The account service charge would charge each new account a one time $5.00 fee to recover the nonrecurring clerical costs of setting up or changing a customers service account. The Company estimates the associated clerical costs of setting up an account is approximately $6.50 (Exh. 7, p. 2). Presently the Company does not charge for new residential connections made during normal business hours.

Currently, the Company pays interest on customer deposits based on judgments in the Superior Court in Montana. The Company asserts this is incorrect, and proposes that the basis for interest rates be changed to the rate specified in Section No. 38.5.1107, Administrative Rules of Montana. Those rules would establish an interest rate of 1 percent per month (Exh. 7, p. 2).

The standby power schedule the Company proposes is Large Partial Requirements Service, 1,000 KW and over, Schedule 33T. This schedule would provide large general service Customers with a source of backup power. Potential customers for this schedule would be industries with the potential to meet all or part of their power needs through cogeneration. None of PP&L's current customers meet the requirements for this tariff (Exh. 7, pp. 12-13).

MCC Rate Design

Overview. MCC rate design recommendations center on three issues of residential rate design; seasonality, basic charges, and pricing structures. MCC presents two options for residential rate structures using revenue requirements as reconciled to the MCC's COS study. Both options are centered around the Company's existing rate structure with adjustments to consumption blocks.

After analyzing load patterns on the Company's Montana system, MCC has determined that seasonality does exist, and recommends that PP&L's present seasonal definition remain a component of residential rate design.

MCC's COS study indicates that a $6.00 basic charge for residential customers could be justified, but is recommending that the basic charge only be raised from the current rate of $4.00 to $5.00 per month (Exh. MCC-2, p. 58). Option A would set the basic charge at $5.00 and leave the tailblock energy charges equal to the present levels. Net energy prices for the initial block would then be lowered from 3.384 ¢/kWh to 1.518 ¢/kWh for both seasons (Exh. MCC-2, J.D.-3, p. 2).

Option B also has a basic charge of $5.00, but the energy price adjustments are made to both blocks. Net energy prices of the initial block are lowered by the amount of the increase in the basic charge and net energy prices in the tail block are lowered by the reduction in residential class revenue requirements. As a result, the net energy charge for the initial block would decrease from 3.384 ¢/kWh to 2.968 ¢/kWh for both seasons. Net energy prices for the tailblock would fall from 5.144 ¢/kWh to 4.494 ¢/kWh in the winter and 4.61 ¢/kWh to 4.06 ¢/kWh in the summer (Exh. MCC-2, J.D.-3, p. 3).

<u>Other Rate Classes</u>. MCC makes no rate design recommendations for PP&L's other rate classes, except that rate components for each class be increased by the overall percentage increase in class revenue requirements as obtained in MCC's COS study (Exh. MCC-2, p. 59).

<u>Other Changes</u>. MCC makes no recommendations as to the appropriateness of establishing a customer account charge, changing the basis for obtaining interest rates for customer deposits, or the addition of the Company's proposed standby power rate, Schedule 33T.

<u>NRDC Rate Design</u>

Overview. NRDC's rate design testimony centers on two aspects of residential rate design, residential class rate design and PP&L's experimental Clean Air/Winter Saver (CA/WS) rate.

Seasonality. Noting that the seasonal differentiation is the only peak-related signal that residential customers receive, the NRDC recommends that PP&L's present use of seasonality remain a component of residential rate design (Exh. 3, p. 20).

Residential Rate Design. One of NRDC's proposals is to retain the current structure and prices of PP&L's residential class and another proposal would convert the current basic charge of $4.00 a month into a minimum charge. NRDC's recommendations are summarized as follows:

> Q. How, specifically, should the Commission respond to Pacific's rate structure proposals?
>
> A. Given the weakness of Pacific's argument for change, the status quo commends itself strongly. I have already explained why tailblock rates should be held at least at current levels, notwithstanding regional surpluses. This argues for rejecting both Pacific's declining block rate and the 50% increase in the Company's Basic Charge; since revenues must be held constant in the proceeding, any increase in the Basic Charge would dilute the already inadequate signal that is being sent by the energy charge. The necessity for such a sacrifice in efficiency is dubious when other investor-owned utilities in the region are setting their Basic Charge at $4.00 per month (the current Pacific level) or less.

> ...I would urge this Commission to follow Idaho's example by converting the Basic Charge to a minimum charge, which disappears once a relatively low threshold of consumption is reached. ...The Company also wants to remove seasonal definition, which is appropriate if in fact its costs are independent of seasonal consumption patterns. This is intuitively implausible; BPA's current New Resources Rate, for example, includes a 4 mills/kWh gap between summer and winter energy costs, reflecting the premium that even a hydro-dominated system places on standing ready to meet winter peaks (Exh. 30, p. 25).

Clean Air/Winter Save Rate. NRDC argues that PP&L did not duly advise customers of the temporary nature of the rate and did not follow the Commission's guidelines for implementation of the rate, allowing customers with fireplaces to qualify for the rate. The NRDC recommends that the Commission reject the CA/WS rate, urging the Commission to set strict guidelines on any future promotional electric rates (Exh. 30, pp. 27-29).

Public Testimony of the NWPPC

Public testimony was offered at the PP&L hearing by Mr. Litchfield and Mr. Gibson on behalf of the Northwest Power Planning Council (NWPPC). Mr. Litchfield and Mr. Gibson provide two general rate design recommendations to the Commission:

> Briefly, the first recommendation is that rates be designed on the basis of regional marginal cost. The second recommendation

> is that the appropriate rate element for comparison to marginal cost is the marginal price rather than the average rate level. In practice this means that the tailblockshould be based on marginal cost (Exh. 28, p. 2).

NWPPC presents the cost basis, as a "test", for determining when inverted or declining block rates are appropriate. Conceptually, an inverted block rate design is appropriate when pricing all consumption at marginal cost generates revenues in excess of the revenue requirement for that class. In order to match marginal cost revenues with the revenue requirement an initial block of consumption would be priced at a lower rate, resulting in an inverted block rate. A declining block rate is appropriate if the same comparison yielded marginal cost revenues below the revenue requirement for that class (May 5, 1987 TR, p. 56).

PART F

RATE DESIGN STIPULATION

On September 10, 1987, PP&L, MCC, and NRDC entered into a stipulated settlement designed to resolve all contested issues in this proceeding. The Stipulation is contingent upon the "substantial" approval of PP&L's proposed Phase II, declining block, residential rate design by the Commission. In the Stipulation, MCC and NRDC have withdrawn their objections to the residential rate design proposed by PP&L. In turn, PP&L is required not to propose an increase for its Montana customers and to file a full COS study in its next filing. Additionally, PP&L is required to engage in least cost planning in the form of conservation acquisition and to adjust or eliminate its declining block residential rate when it acquires new, higher cost capacity, or purchases higher cost power.

The cost of service (COS) provisions of the Stipulation require the Company to file a full COS study in its next filing. The Stipulation lists the anticipated date for that filing as November 1, 1987. The Commission anticipates this filing within two weeks of the the date of this Order.

The Stipulation sets a five item action plan for conservation acquisition. The first item requires PP&L to adopt Model Conservation Standards (MCS) for its residential conservation programs and to achieve penetration equivalent to that of BPA's Super Good Cents program. PP&L is required to provide cash incentives if the penetration targets outlined in the Stipulation are not met. The second item requires PP&L to modify its Oregon Zip weatherization program. The third item requires PP&L to commit $100,000 to achieving proportional low income participation in weatherization programs. The fourth item requires PP&L to support BPA's "Energy Efficiency Award" program and to provide up to $1.7 million for developing programs that encourage consumers to purchase high efficiency appliances. The final conservation item requires PP&L to promote energy efficiency in its future marketing programs. Additionally, the Stipulation requires PP&L to notify customers that this rate is likely to be temporary (Stipulation, pp. 3-8).

As previously mentioned, the Stipulation requires PP&L to raise or eliminate the tail block rate under certain conditions. The tailblock price would be adjusted if either; 1) PP&L buys power from BPA under the New Resources Rate and BPA acquires resources with costs above both the New Resources Rate and PP&L's tailblock rate, or 2) it is likely that PP&L will have to buy power or purchase a plant with costs exceeding PP&L's average system cost (Stipulation, p. 9).

The Company, MCC, and NRDC agree that this Stipulation is made for settlement purposes only and is the express intent of the Company, MCC and NRDC that this agreement is meant to address the Company's proposed Phase II residential rates, including the COS study employed in calculating those rates.

PP&L, MCC and NRDC agree that the matters settled herein do not constitute and cannot be considered as precedent for any future proceeding. It is expressly understood and agreed that no party to this Stipulation, by entry into this Stipulation, shall be deemed to have accepted, agreed to, or conceded to any particular ratemaking principle, cost of service determination, or legal principle underlying any of the provisions of this Stipulation.

PP&L, MCC and NRDC agree that no party, by consenting to the approval of this Stipulation by the Commission waives any claim, right, defense, or legal argument which it may otherwise have with respect to any matters specified in the Stipulation.

PART G

COMMISSION'S DECISION ON COS/RD ISSUES

Background: Marginal Cost Pricing

As a preliminary matter, the Commission supports marginal cost pricing, meaning that prices should reflect long-run marginal costs to the greatest extent possible. Any deviation from setting prices at long-run marginal cost should be on a short-term basis only. The concept of marginal cost pricing manifests itself in rate design in many ways. Prices which vary by rate class, by time-of-year, by time-of-day, or by rate structure are developed to track costs more closely. Rate structures are used to track marginal costs by separating rates into the separate components of service, (demand, energy, reactive power, and customers costs), or by featuring inverted or declining block energy rates.

The application of marginal cost pricing requires that rates should be designed so that customers "see" a price that is representative of the long-run marginal cost of serving those customers. Generally, the tailblock price is the marginal rate that consumers face. If tailblock prices are set below marginal costs, consumers make inefficient consumption decisions, causing the utility to purchase marginal cost resources at substantially higher costs than the revenues they are providing. In turn, rates will have to be increased to all customers. Conversely, if prices are set above marginal costs, consumers make inefficient capital investments to reduce consumption, or forego consumption inappropriately because the cost of serving those customers is less than the prices they "see". Prices above or below long-run marginal costs are equally undesirable, and the Commission accepts the NWPPC's recommendation that marginal (tailblock) rate should be set at marginal cost (May 5, 1987 TR, p. 52-58).

The Commission believes that the "test" presented by the NWPPC is appropriate for determining whether an inverted or declining block rate structure should be implemented in rate design. In the instant docket, pricing all kWh consumed by PP&L's residential rate class marginal cost would generate revenues below its embedded revenue requirement. Consequently, some portion of the class' tariff, either the customer charge or the price of the initial block, has to be increased so that the revenues generated equal the class' revenue requirement. Using the NWPPC's "test", the Commission finds the Company's proposed Phase II residential rate structure as stipulated to by NWPPC, NRDC, and MCC, to be a proper application of declining block rates.

The Stipulation

The Commission finds that the goal of acquiring cost effective conservation is rational at all times, regardless of whether the utility or the region is experiencing an energy surplus or an energy shortage. The Commission also finds that the objectives of setting marginal (tailblock) rates at marginal cost and the acquisition of cost effective conservation resources are two separate goals which are not mutually exclusive. The goals of setting prices at marginal cost and acquiring cost effective conservation should be encouraged at all times, even when these goals appear to be in conflict.

The Commission finds the Stipulation to be an acceptable solution to the residential rate design issues in this proceeding.

The Commission approves the Company's Phase II two-block declining energy rate.

The Commission rejects the Company's proposed Phase II $6.00 basic charge, choosing to approve a $5.00 basic charge. The Commission finds that the revenues associated with the lower basic charge must be recovered from initial block consumption.

In accepting this Stipulation, the Commission reminds the parties that all issues and matters in this filing will again be closely scrutinized in the next general filing of PP&L and that the Commission's acceptance of the Stipulation in this proceeding will have no bearing on its decisions in any future proceedings.

<u>Other Rate Design Issues</u>

<u>Employee Discount</u>. The NWPPC has testified that if tailblock prices are set below marginal costs, consumers make inefficient consumption decisions, causing the utility to purchase marginal cost resources at substantially higher costs than the revenues they are providing (May 5, 1987 TR, pp. 53-54). The principle that customers should not receive prices which are below marginal cost led Commission to require that employees not receive an additional 50 percent discount in the CA/WS filing: "Absent this provision, PP&L's employees could receive a commodity price that falls below marginal cost" (Finding of Fact No. 8, Docket No. 86.11.61, Interim Order No. 5235).

The Commission finds that PP&L's employee discount of 25 percent to the total bill is no different than applying a 25 percent discount to each rate component (PSCR-179). Under Phase II rates, the 25 percent employee discount would lower the tailblock price below long-run marginal costs. Therefore, the Commission requires that no employee be allowed to receive tailblock prices which are below the long-run marginal cost of 3.609 ¢/kWh.

Cost of Service

Introduction. The Commission agrees with the Company's and the MCC's use of marginal costs in determining cost of service. Correctly calculated, prices based on marginal costs allocate society's resources in an efficient manner, conserving scarce resources. As stated by MCC, the use of marginal costs leads to rates that meet the objectives of encouraging conservation, efficiency, and equity (Exh. MCC-2, p.11). As has been the Commission's policy in previous dockets, it is appropriate, as the MCC has recommended here, to use marginal costs to determine both inter-class and intra-class revenue responsibilities (Exh. MCC-2, p. 12).

As a preliminary matter, the Commission is concerned that the Company is proposing prices which are based on marginal costs presented in 1986 dollars. Clearly, the earliest final prices out of this docket will be tariffed is December 1987. Moreover, the cost-based prices resulting from this docket may be in place well into 1989. Therefore, the Commission believes that the next marginal cost study presented to this Commission should be in terms of dollars representative of the time frame for which the resulting prices will be in place. At a minimum, this should be presented as an alternative in the next COS filing.

Generation. The Commission finds the use of real carrying charges to be appropriate and is pleased that both the PP&L and MCC have used real carrying charges in their COS stud ies. Generally, the Commission finds relatively more merit in the Company's Base-Peak approach than MCC's mixing of combustion turbine demand costs with the Company's energy costs, and chooses to follow its precedent from Order No. 5169a, Docket No. 85.10.41.

However, the Commission believes that the Company's application of the Base-Peak approach may be flawed. As stated previously, the Company uses avoided costs to measure baseload capacity <u>and</u> energy costs for the first 8 years of the 20-year forecast. However, the Company indicates that its avoided costs contain no fixed costs, just energy costs (May 6, 1987 TR, p. 21). MCC finds the Company's application of the Base-Peak approach in this manner to be inconsistent (May 5, 1987 TR, pp. 186-188). The theoretically correct application of the Base-Peak approach appears to measure generation energy costs by adding the variable costs of baseload capacity to, the fixed costs of baseload capacity less the fixed costs of peakload capacity, or:

$$VC_B + (FC_B - FC_P)$$

Where: FC = Fixed Costs
VC = Variable Costs
B = Baseload Plant
P = Peakload Plant

The Commission finds that PP&L's present use of avoided costs to measure baseload capacity demand and energy costs leaves out the the fixed costs of baseload capacity. In future filings, the Commission requires PP&L to either; 1) correct its Base-Peak generation energy calculation to conform with this methodology, or

2) provide this Base-Peak generation energy calculation as an alternative proposal.

Transmission. Generally, the Commission accepts the Company's proposed marginal transmission demand and energy costs. However, the Company's calculation of marginal transmission energy costs also appears to contain a technical flaw. In the development of marginal transmission energy costs PP&L uses a 66 percent load factor. Mr. Duvall explains:

> When converting from kilowatts to kilowatt hours, you need the proper conversion factor in order to keep the consistency. The load factor is simply a measure of how many kilowatt hours per kilowatt are used. (May 6, 1987 TR, p. 26)

The Commission does not accept the witness' consistency argument. Rather, the Commission believes that the Company's conversion of marginal transmission energy costs is inconsistent with the Company's own proposed methodology for converting marginal generation energy costs. In the conversion of marginal generation energy costs from kilowatts to kilowatt hours the Company simply divides kilowatts by the number of hours in a year. Accordingly, the Commission requires that in any future COS/RD filing, the Company either justify the use of a load factor in its conversion of marginal transmission energy costs, and/or present the use of its marginal generation energy costs conversion methodology for the conversion of marginal transmission costs, as an alternative.

Seasonality. The Commission finds neither PP&L's or MCC's development of seasonality to be correct. In light of PP&L testimony indicating that PP&L's costs do vary by time-of-year, the Commission finds the Company's proposal to tariff a non-seasonally differentiated residential rate in the absence of a detailed cost study to be unsupported (May 6, 1987 TR, pp. 27-28). The Commission also believes that the Company's proposal is inconsistent in its treatment of different rate classes; proposing no seasonal differentiation in rates for the residential rate class, yet retaining the current seasonal differentiation for its other rate classes. Additionally, PP&L has indicat ed that it will most likely seek to have the seasonal differential eliminated for its other rate classes in future filings (May 6, 1987 TR, pp. 71-72).

Accordingly, MCC's proposal to retain the current seasonal definition without a detailed cost study is also inadequate. The Commission's concern is that if costs vary by season, or by time-of-year, and prices do not, uneconomic consumption occurs throughout the year. Prices should reflect costs to the fullest extent possible. The Commission requires PP&L to include detailed cost analysis supporting its seasonal recommendations for energy and demand in its next COS/RD filing.

Customer. Although the Commission recognizes that marginal customer costs are relatively less crucial than say generation costs, the Commission emphasizes the importance of all COS components in the development of cost based rates. The Commission believes that the MCC's approach of using embedded costs to approximate marginal customer costs is less than optimal. However, PP&L's marginal customer cost calculation is also less than optimal. The Commission agrees with Mr. Duvall that separating the Company's calculation of marginal customers into residential marginal customers and "other" marginal customers could serve to be an improvement in accuracy of the study, and directs PP&L to incorporate this change in its next COS filing (May 6, 1987 TR, p. 27).

Concerning the Company's proposed marginal customer costs, in following its precedent from Order No. 5169a, Docket No. 85.10.41, the Commission would note that it is moving towards the concept of using opportunity costs as an appropriate measure of marginal customer costs, (see Finding of Fact No. 277-278, Order No. 5219b, MDU Docket No. 86.5.28). This issue will be revisited in future filings.

Reactive Power. The Company indicates that the reactive power charges contained in its Montana rates are a result of studies conducted in other jurisdictions (PSCR-181). The Commission requires that the Company calculate the marginal cost of reactive power for each rate class which currently has a reactive power charge in its next COS/RD filing.

Employee Discount. The Company indicates that the cost of the 25 percent employee discount is spread to all rate classes (PSCR-166). The Company's argument does not not convince the Commission. It is clear to the Commission that including all associated employee billing determinant volumes in the residential class has the impact of placing the burden of this fringe benefit expense on just the residential class. Employee costs are incurred to serve all customers and consequently these costs should be borne by all of PP&L's customers. On the other hand, no party has proposed a methodology for determining each rate class' causal responsibility for the cost of the employee discount.

Until such time that the issue is debated, the Commission finds that the portion of the residential rate class' reconciled revenue requirement associated with the employee discount must be identified and recovered from all rate classes on a per kWh basis in the following manner. First, the Company is required to design residential rates as if the employee discount does not exist. Using those prices, and employee billing determinants, calculate the total cost of the employee discount. In the third step, reduce residential revenue requirements by the cost of the employee discount and redesign residential rates, factoring the 25 percent employee discount into the calculation. In the last step, the Company is to recover the cost of the employee discount from all rate classes on a KWH basis. In future filings, PP&L is required to separate out and show, for accounting purposes, the cost and recovery of the employee discount.

<u>Reconciliation</u>

The Commission's general acceptance of the Company's COS study combined with the stipulated revenue requirement and the Stipulation of COS/RD issues alleviates the need for a reconciliation procedure in this proceeding. As a policy matter, the

Commission has not deviated from the equal percent reconciliation approach in any recent electric docket e.g, Finding of Fact No. 82, Order No. 5219c, Docket No. 86.5.28.

PART H

OTHER ISSUES

Experimental Clean Air/Winter Saver Residential Service Rate. On October 10, 1986, PP&L filed tariff for the authority to implement an experimental Clean Air/Winter Saver (CA/WS) rate. The CA/WS rate is an option to the standard residential rate and was designed to regain residential electric space heating load lost to wood heating. The CA/WS rate features a $5.00 monthly fee and a 50 percent discount to the net tailblock price of the standard residential rate. This tailblock discount has the effect of changing the existing inverted block rate into declining block rate, under current tariffed rates. On November 24, 1986, the Commission approved the CA/WS rate on an experimental basis, in Interim Order No. 5235, Docket No. 86.11.61. The Commission does not grant final approval of the CA/WS rate, Schedule 10.

Partial Requirement Service Schedule 33T. The Company has proposed to establish a partial requirement service schedule for customers with demand in excess of 1,000 kilowatts. This rate schedule is designed to serve standby power to facilities who fill all or part of their power requirements through cogeneration and rely on PP&L to provide back-up power on a standby basis. Under the proposed schedule, all demand and energy usage in excess of contracted loads (or excess takings) would be charged 4 times schedule 48T rates. The Company notes, that this schedule is similar to the standby rates in effect in PP&L's other jurisdictions (Exh. 7, pp. 12-13).

For the following reasons the Commission denies PP&L's proposal to tariff Schedule 33T. First and foremost, PP&L has not presented evidence indicating whether the excess takings charge of 4 times Schedule 48T rates is justified on the basis of the cost of providing standby power. Second, PP&L has indicated that there are currently no partial requirement customers in its Montana service territory, so that the potential customers of Schedule 33T have not been represented in this proceeding (Exh. 7, pp. 12-13). Lastly, PP&L witness Pienovi's discussion of standby rate casts doubt on the design of the rate:

> Q. Did the Company in this situation, did the Company have a standby tariff that was in effect in Washington at that time?
>
> A. I believe yes, we did have a standby tariff. And if my memory serves me correct, Mr. Servaitis would be the better person to ask about this specifically. But one of the things--or one of the elements of pricing flexibility, I think, that would be useful for us folks on the future is the appropriateness of standby power charges that this industry has historically formulated. I'm not convinced; I don't know, but I'm not--I do not feel comfortable in assuming that we are charging an appropriate price for that service (May 5, 1987 TR, pp. 145-146).

Other Rate Design Issues. The Company has proposed several other tariff changes to the Commission which do not fall within the COS/RD portion of this docket. Those changes are a proposal to establish an Account Service Charge, change the interest calculation on customer deposits, and clarify the date after which master metering of apartments is no longer allowed.

The proposed Account Service Charge would establish a $5.00 fee for each new account established, or change in account responsibility at a given service location. The Commission denies the Company's proposed Account Service Charge.

The second tariff change, proposed in Exh. 7, p.2, changes the interest charge calculation on customer deposits from the interest rate as established by judgements in the Superior Court of the State of Montana to the interest rate established in Section No. 38.5.1107 of the Administrative Rules of Montana. The Commission approves the proposed change.

The third tariff change, proposed in Exh. 7, pp. 2-3, clarifies the date after which master metering of apartments is no longer allowed. The Commission approves the proposed change.

CONCLUSIONS OF LAW

1. The Applicant, Pacific Power and Light Company, furnishes electric service to consumers in Montana, and is a "pub lic utility" under the regulatory jurisdiction of the Montana Public Service Commission. Section 69-3-101, MCA.

2. The Commission properly exercises jurisdiction over the Applicant's rates and operations. Section 69-3-102, MCA and Title 69, Chapter 3, Part 3, MCA.

3. The Commission has provided adequate public notice of all proceedings and opportunity to be heard to all interested parties in this Docket. Title 2, Chapter 4, MCA.

4. The rate level and rate structure approved herein are just, reasonable, and not unjustly discriminatory. Section 69-3-330, MCA.

ORDER

1. The Pacific Power and Light Company shall file rate schedules which reflect no change in annual revenues.

2. The rates authorized herein shall be effective for service rendered on and after December 4, 1987.

3. Findings of fact Nos. 107, 110, 111, 113, 114, and 116 shall apply to any cost of service filing submitted after January 15, 1988.

4. Rate schedules filed shall comport with all Commission determinations set forth in this Order.

5. The Applicant's tariff submittal shall reflect the current BPA Exchange Credit for qualifying schedules.

6. The revenue requirements/rate of return Stipulation is accepted for purposes of this proceeding.

7. Dkt. No. 86.11.62(14) is consolidated into this Docket.

8. The Cost of Service/Rate Design Stipulation is accepted for purposes of this proceeding.

9. Except for the Commission concerns and determinations discussed in Finding of Fact No. 24 in this Order, the Commission orders that Docket Nos. 86.11.61 and 86.11.62 (14) are closed as a result of this Order.

10. All motions and objections not ruled upon are denied.

DONE AND DATED this 4th day of December, 1987, by a 3 - 1 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

HOWARD L. ELLIS, Commissioner

TOM MONAHAN, Commissioner
Dissenting

DANNY OBERG, Commissioner

JOHN B. DRISCOLL, Commissioner

ATTEST:

Ann Purcell
Commission Secretary

(SEAL)

NOTE: Any interested party may request that the Commission reconsider this decision. A motion to reconsider must be filed within ten (10) days. See 38.2.4806, ARM.

DISSENTING OPINION

While I support the Commission's decisions in dockets 86.12.76, 86.11.61 and 86.11.62(14) in most regards, I am forced to dissent because I strongly oppose not only the increase in the basic charge, but its very existence.

At the present time Montana PP&L customers pay a $4.00 basic charge. In this order that charge will be raised to $5.00 and will have its greatest impact upon those least able to pay it.

As a percentage, those with lowest consumption pay the greatest portion of a basic or service charge. A $4.00 service charge is only a 4% rate for a customer using $100.00 worth of energy a month, but a 20% rate for a customer using only $20.00 worth of energy. This inequity, in every regard identical to a sales tax, makes it unacceptable to me.

As a practical result, the increase in the service charge will induce more customers to seek alternative fuels and makes a mockery of the experimental clean air/winter saver residential rate which was approved by the Commission on November 24, 1986 and which is a part of the order in this consolidated docket.

____
Tom Monahan
Commissioner